AEMC

REVIEW

Australian Energy Market Commission

FINAL REPORT

Review of the application of capacity trading reforms in the Northern Territory

16 March 2018

Reference: GPR0006
Final Report

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

Reference: GPR0006

Citation

AEMC 2018, Review of the application of capacity trading reforms in the Northern Territory, Final Report, 16 March 2018, Sydney

About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Foreword

The Northern Territory (NT or territory) gas market has for many years been isolated from other Australian gas markets with no interconnecting pipelines to either the west or east coast. The gas market has historically been dominated by the supply of gas fired generation (GFG) without the large residential and industrial markets for gas seen in the east coast. The relatively small size of the market has meant both supply and transport have been contracted through a limited number of long-term agreements, generally entered into by NT government owned entities.

In the NT, the flow of gas has undergone significant change in recent years with gas supply moving from predominantly the Amadeus basin at the southern end of the Amadeus gas pipeline (AGP) to predominantly the Blacktip field offshore NT at the northern end of the AGP. This has had implications for the utilisation of pipelines in the NT.

Further changes to the structure of the market are imminent. The commissioning of the Northern Gas Pipeline (NGP) expected towards the end of 2018 will see interconnection of the NT to the wider east coast market for the first time and the beginning of gas flow from the territory into other regions. In addition to the connection of the NGP, new gas demand in the NT presents opportunities for economic development and the more efficient utilisation of existing pipeline infrastructure.

The changing nature of gas demand for GFG as a result of the NT government's renewables policy and the improving economics of solar generation in the NT will require a more flexible gas supply chain in the future. GFG will still be required to supply peak load, while increased levels of renewable generation will reduce the average electricity generated from GFG as a whole.

The Energy Council's Vision for Australia's future gas market

The gas market on the east coast of Australia including the NT is undergoing a structural change due, in part, to the interconnected nature of the pipeline network. Recognising this change, the Council of Australian Government Energy Council (COAG Energy Council) established the Energy Council's Vision (the Vision) to promote a liquid wholesale gas market, in part achieved by increased flexibility and trade in pipeline capacity.

The Vision is for a liquid wholesale market that:

- provides market signals for investment and supply
- where responses to those signals are facilitated by a supportive investment and regulatory environment
- where trade is focused at a point that best serves the needs of participants

- where an efficient reference price is established
- where producers, consumers and wholesale markets are connected to infrastructure that enables participants to readily trade between locations and arbitrage trading opportunities.

On 20 February 2015, the COAG Energy Council requested the Australian Energy Market Commission (the AEMC or Commission) to undertake a review of the design, function and role of facilitated gas markets and gas transportation arrangements on the east coast of Australia (the east coast review). The stage 2 final report of the east coast review was published in May 2016 and made several recommendations related to the east coast gas market. As the NT was not connected to the remainder of the east coast at the time of the east coast review, the NT and the application of the recommendations to the NT were not specifically considered.

The capacity trading reforms

Four of the recommendations from the east coast review relate to trade in pipeline capacity (the pipeline capacity reforms). These interlinked capacity reforms are:

1. **A day-ahead auction of contracted but un-nominated pipeline capacity**: the auction is to have a reserve price of zero dollars, with compressor fuel provided by shippers in kind. The auction is a mandatory mechanism where all contracted but un-nominated capacity goes into the auction. The incumbent shipper maintains its right to nominate or renominate after the auction is completed. In order to maintain an incentive on the incumbent shipper to sell capacity prior to the auction, auction revenue is to be allocated to service providers.

2. **A capacity trading platform(s) to facilitate sales by capacity holders ahead of the auction and provide for exchange based trading**: an electronic anonymous exchange based platform for commonly traded products and a capacity listing service to be run by the Australian Energy Market Operator (AEMO).

3. **Standardised provisions in capacity agreements to make capacity more fungible**: standardisation of key primary and secondary capacity contractual terms for pipeline and hub services (e.g. key operational and prudential provisions in Gas Transportation Agreements (GTAs) and Capacity Transportation Agreements (CTAs)).

4. **A reporting framework for secondary trades of pipeline capacity and hub services**: publication of information on all secondary trades of pipeline capacity and hub services. The information to be published includes the price of the trade and any other information that might reasonably influence the price.

Increased flexibility and opportunity for trade in pipeline capacity is a key policy that will help to achieve the Vision. The capacity reforms currently being developed for the east coast by the Gas Market Reform Group (GMRG) have been designed to address a number of factors that the Commission found were limiting shippers access to competitively priced secondary transportation capacity on key transmission pipelines including:

- high search and transaction costs, particularly for shorter term capacity trades
- the bespoke nature of transportation agreements, which can impede the development of fungible capacity products and limit the pool of potential buyers and sellers
- the lack of public information on the prices paid for secondary capacity, which means shippers are unable to readily assess the market value of capacity.

The purpose of the Northern Territory review

Given the imminent connection of the NT gas market to the wider east coast market, the COAG Energy Council requested the AEMC in the terms of reference to undertake a review to consider whether the capacity trading reform package should be implemented in whole, or in part, in the NT. This review, as part of the Commission's assessment, has taken the institutional and commercial arrangements of the NT market into account. The review has involved consultation with key stakeholders in the NT market.

With the impending connection of the NT with the rest of the east coast market via the NGP, the review has also taken into account the impact of implementing these reforms in the NT on the wider east coast market.

The Commission's findings and recommendation

In its assessment of the application of the reforms in the NT, the Commission has taken into account that the wider east coast market is characterised by several interconnected markets that may each have different supply, demand and operational characteristics.

While interconnection will result in gas flow between the NT and the wider east coast market, it does not imply gas prices will be closely linked. The distances involved and the cost of transport between the NT and the wider east coast market is likely to result in differences between NT and east coast gas contract prices, as well as the level of price volatility.

The Commission has found that currently the secondary trading of pipeline capacity in the NT is severely limited. The issues that were found in the rest of the east coast to have limited secondary capacity trade have also been found to apply in the NT. As a result, the benefits of the capacity trading reforms the Commission identified in the east coast review will also arise in the context of the entire interconnected east coast market, including the NT.

The day-ahead auction of contracted but un-nominated pipeline capacity is likely to promote increased trade of secondary pipeline capacity, particularly on sections of the network that are underutilised at present. It should assist with trade across multiple pipelines and into the rest of the east coast market. The combinatorial nature of the auction will make short-term trades across multiple pipelines much easier, and will provide more information to the market on the cost and utilisation of particular routes.

The capacity trading platform will help to lower search and transaction costs and the time taken to execute trades for secondary capacity trading in the NT. It will improve the incentive primary capacity holders have to trade un-utilised capacity and it will provide shippers with confidence that secondary trades are non-discriminatory.

Standardisation will help to reduce the provisions in capacity contracts that need to be negotiated. This will make capacity products more fungible thereby increasing the potential pool of buyers and sellers of capacity on the capacity trading platform and reduce the time and cost to transact. While the pool of buyers and sellers in the NT is expected to be small to begin with, the interconnection with the wider east coast market and potential new developments in the NT over time should increase the pool of participants on the platform.

The reporting framework will assist to alleviate confusion in the market around the type of products that are offered, such as firm versus as available, and the market value of capacity on different parts of the network. Over time it will enable shippers to engage in more effective negotiations and provide them with the confidence that access is being provided on a non-discriminatory basis. In so doing it should expedite the transaction process.

The capacity trading reforms will help lower barriers to entry for new supply and potential load looking to source gas supply in the NT market. Better information on the cost of particular routes will aid both gas supply and gas consuming projects in assessing the economics of new development in the NT. Further, the package of reforms should lead to more efficient utilisation of pipelines over the long term, through incentives on incumbent shippers to trade spare capacity, and over the short term through the mandatory auction mechanism.

While the reforms will have costs associated with their implementation and operation in the NT, these costs are expected to be incremental given the same market participants are required to implement the reforms in their east coast operations. Further, the benefits to consumers on the whole of the east coast including those in the NT from the reforms, are likely to outweigh these potential costs.

Currently, in the NT there is the potential that only one bidder will participate in any day-ahead auction. If this were to occur, it would be expected that the bidder would be able to obtain secondary capacity at the reserve price (which is zero dollars plus compressor fuel in kind). Further, given that part of the pipeline is currently under-utilised, that shipper may have some certainty that any capacity obtained through the auction would not be interrupted. However, the Commission considers that it is not an inefficient outcome of the auction for a participant to receive such capacity for zero dollars. Rather, this result will lead to the efficient use of the pipeline by those parties that value it.

A component of the NT gas market that is not common in the rest of the east coast gas market is the ownership structure of Power and Water Corporation (PWC) and

Territory Generation (TGen). These parties are government owned and have a vital role in providing electricity in the NT. Further, there is an informal requirement that these parties act as supplier, either of gas or electricity, of last resort. As a result, the contracts these parties entered into for supply and transportation may not have the same terms and conditions as you would expect from a private enterprise.

The Commission understands that PWC has fully contracted the firm capacity on the entire length of the AGP to ensure that it has available capacity at all times to meet peak demand associated with electricity generation. However, as not all the capacity is needed at all times, it can be assumed there will be times when that capacity will be placed in the day-ahead auction. This may result in PWC’s competitors, or TGen, being able to obtain transportation capacity for less than PWC’s costs. This may result in PWC either losing out on new contracts (either for transportation, gas supply or both) or entering those new contracts at below their cost level. This may then have an impact on NT taxpayers.

Although we are aware that there are possible impacts on taxpayers as a result of the structure of the parties and contracts in the NT market, the ownership issues in the NT are not something that the Commission can take into account when assessing whether the proposed reforms contribute to the achievement of the National Gas Objective (NGO). Rather, these issues are best addressed by the NT government in balancing the various economic benefits that may arise from the reforms and the possible balance sheet impacts resulting from any competitive pressures on PWC.

The capacity trading reforms will facilitate increased secondary capacity trading by using market based process to allocate capacity on a non-discriminatory basis to those that value it most highly, reduce search and transaction costs associated with secondary trades, reduce information asymmetries and aid the price discovery process all of which is in the long-term interests of consumers. This is the same for the NT market as with the wider east coast market.

Therefore, the Commission recommends that the capacity trading reforms, in whole, should be implemented in the NT.

Contents

1 Introduction

1.1 Background

In May 2016, the Australian Energy Market Commission (the AEMC or Commission) completed its review of east coast wholesale gas markets and pipeline frameworks (the east coast review).

In the east coast review the Commission found that a number of factors were limiting the ability of shippers to access competitively priced secondary transportation capacity, including:

- high search and transaction costs
- the bespoke nature of transportation agreements, which can impede the development of fungible capacity products and limit the pool of potential buyers and sellers
- the lack of public information on the prices paid for secondary capacity, which means shippers are unable to readily assess the market value of capacity.

To address these issues, the Commission recommended, in the east coast review, the introduction of four capacity trading reforms:[1]

1. A day-ahead auction of contracted but un-nominated pipeline capacity to be conducted shortly after nomination cut-off.
2. A capacity trading platform(s) to facilitate sales by capacity holders ahead of the auction and provide for exchange based trading.
3. Standardised provisions in capacity agreements to make capacity more fungible and allow shippers greater receipt and delivery point flexibility.
4. A reporting framework for secondary trades of pipeline capacity and hub services.

Together the Commission expected this package of reforms to promote the National Gas Objective (NGO) and the COAG Energy Council's Vision (the Vision)[2] to promote a liquid wholesale gas market, and in so doing:

- improving the efficiency with which capacity is allocated and used on transportation assets operating under the contract carriage model

---

1 AEMC, Stage 2 Final Report, *East Coast Review*, 23 May 2016, p67

2 COAG Energy Council Australian Gas Market Vision (December 2014) http://www.coagenergycouncil.gov.au/publications/coag-energy-council-australian-gas-market-vision

- facilitating increased trade in gas and supporting the development of a more robust reference price for gas in the east coast.

On 19 August 2016, the Council of Australian Government Energy Council (COAG Energy Council) agreed to implement the capacity trading reform package and tasked the Gas Market Reform Group (GMRG) with the design, development and implementation of these reforms.[3] On 24 November 2017, the COAG Energy Council agreed that the capacity trading reform package should be implemented by 1 March 2019.[4]

It is expected that the COAG Energy Council will consider the Commission's recommendations in this review at their next meeting. If it is determined that the capacity trading reforms should apply in the Northern Territory (NT), then the exact date of implementation will be determined through the GMRG's consultation process on the gas reform package. Alternatively, if it is determined that the capacity trading reforms should not apply in the NT, a derogation from the law, as applicable, and the rules will need to be approved by the COAG Energy Council.

1.2 Purpose of the review

The east coast review did not explicitly consider gas or transportation capacity markets in the NT. The purpose of this NT review is to consider whether the capacity trading reforms, which are currently being implemented in the remainder of the east coast, should also be implemented (in whole or in part) in the NT.

In its assessment of the application of the reforms in the NT, the Commission has taken into account that the wider east coast market is characterised by several interconnected markets that may have different supply, demand and operational characteristics.

While interconnection will result in gas flow between the NT and the wider east coast market, it does not imply gas prices will be closely linked. The distances involved and the cost of transport between the NT and the wider east coast market is likely to result in differences between NT and east coast gas contract prices, as well as the level of price volatility.

1.3 Process followed for the review

The Commission has used the same assessment framework as was used in the east coast review. This includes the Vision for the market, the NGO and consideration of the characteristics of a well-functioning gas market. This assessment framework is covered in more detail in chapter 4.

3 COAG Energy Council meeting (19 August 2016) http://www.coagenergycouncil.gov.au/publications/5th-coag-energy-council-meeting-communique-19-august-2016

4 COAG Energy Council meeting (24 November 2017) http://www.coagenergycouncil.gov.au/publications/15th-energy-council-ministerial-meeting

The specific circumstances of the NT gas market have also been taken into account, including:

- the nature of the institutional and commercial arrangements underpinning the supply and transportation of gas in the NT
- the development and imminent commissioning of the Northern Gas Pipeline (NGP), linking the NT at Tennant Creek with the wider east coast market at Mt Isa in Queensland.

The Commission has considered the likely effect of the reforms if applied in the NT on gas and transportation markets and consumers of gas:

- within the NT
- within the wider east coast gas market.

The Commission has consulted with current and prospective gas pipeline owners, shippers and consumers in the NT in conducting the review. The Commission has also consulted with the NT government, the GMRG, the Australian Competition and Consumer Commission (ACCC) and the Queensland government. A list of stakeholders consulted can be found at appendix A.

1.4 Structure of the report

This is the final report for the review of the application of the capacity trading reforms to the NT. The remainder of this document is structured as follows:

- chapter 2 sets out the background and rationale for reforms as they were developed through the east coast review
- chapter 3 provides an overview of the NT gas market, including its physical structure, the key contracts and commercial arrangements and the principal participants
- chapter 4 sets out the assessment framework used for the review and the Commission recommendation on the application of the reforms in the NT
- chapter 5 provides more detail on the assessment of each reform in the context of the NT market
- appendix A provides a list of the stakeholders consulted in conducting the review
- appendix B provides a summary of the final recommendations for the design of the reforms as set out by the GMRG.

2 East coast wholesale gas markets and pipeline frameworks review

2.1 Changes in the east coast market

In May 2016 the AEMC provided the COAG Energy Council with its stage 2 final report on the east coast wholesale gas markets and pipeline frameworks review.

The review was undertaken in response to a number of changes in east coast gas markets. The development of the LNG industry in Queensland has put upward pressure on gas prices, as prices have become linked to international benchmarks. The east coast market has become increasingly interlinked and a number of long-term Gas Sales Agreements (GSAs) have expired leaving domestic users to negotiate new contracts in a very different market. Prices have also become more volatile, in part with the increased linkage of contract prices to international oil prices.

As a result, the Commission found that more flexible and sophisticated means of managing gas portfolios is increasingly important to participants. Greater flexibility in how gas is bought and sold outside of GSAs and new approaches to managing spot price volatility risk is required. The need for this degree of flexibility was largely unforeseen at the time the current market frameworks were developed and it is these factors that have led to a renewed focus on market development to promote efficient outcomes for consumers.

2.2 Principles used in formulating the east coast reforms

Recognising these changes, the COAG Energy Council established a set of principles, referred to as the Vision.[5] A key outcome of the Vision is the establishment of an efficient reference price for gas. A transparent reference price allows consumers to know whether the price they are being asked to pay reflects underlying supply and demand conditions. This requires a liquid market with many parties buying and selling gas.

A liquid trading market is a means to promoting greater efficiency in the supply of natural gas and hence achieving the NGO. The NGO is set out in section 23 of the National Gas Law and states:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."

5 COAG Energy Council Australian Gas Market Vision (December 2014) http://www.coagenergycouncil.gov.au/publications/coag-energy-council-australian-gas-market-vision

An efficient market supports outcomes where gas is supplied to those consumers who value it the highest, at the lowest possible cost over time. A liquid trading market facilitates the buying and selling of gas on an equal basis to other players, and the hedging of price risk, which lowers barriers to entry and promotes competition. Trading gas and capacity through well-functioning markets is fundamental to consumers not only knowing whether price reflects underlying demand and supply, but also forming expectations of future price movements.

2.3 Rationale for the capacity trading reforms

The achievement of the NGO and the Vision of a liquid wholesale gas market depends critically upon the efficiency with which the capacity of pipelines and the compressors used in the provision of hub services is allocated.

While historically long-term contracts have been relatively effective in allocating gas and transportation capacity, changes underway in the market have made the ability to trade transportation capacity between shippers increasingly important. This ability to trade capacity will be critical to the success of the development of a liquid wholesale gas commodity market and an efficient reference price for gas in the east coast.

Although some steps have been taken over the last several years to better facilitate capacity trading between shippers, there are, as stakeholders pointed out in the east coast review, a number of factors that are limiting the ability of prospective shippers to access competitively priced secondary transportation capacity. These limitations include:

- high search and transaction costs, particularly for shorter term capacity trades
- the bespoke nature of transportation agreements, which can impede the development of fungible capacity products and limit the pool of potential buyers and sellers
- the lack of public information on the prices paid for transportation capacity, which means shippers are unable to readily assess the market value of capacity.

These observations are broadly consistent with the finding from the ACCC's Inquiry[6] that while there is evidence of capacity being bought and sold (predominantly under longer term contracts), the factors outlined above are acting as barriers to trade and limiting capacity utilisation and gas flows:

> "Capacity, including secondary capacity/services, is being bought and sold. However, information transparency, search and transaction costs, and also the

6 The ACCC was tasked with reviewing competition in the east coast gas market. The ACCC found that short-term trading options are becoming increasingly important to users. Greater liquidity in wholesale gas markets would improve price discovery and help market participants manage volume fluctuations, while facilitating new entry by retailers in downstream gas markets. The ACCC analysis found that access to pipeline transportation capacity at a reasonable price is also important for the development of the market.

pricing of transportation are barriers to further capacity utilisation and gas flows.[7]"

To address these issues, the Commission, in the east coast review, recommended a number of initiatives which collectively it expects will foster the development of a more liquid market for secondary capacity by:

- enabling capacity to be allocated on a non-discriminatory basis to those that value it most highly through market based processes and, in so doing, improve the efficiency with which capacity is used on pipelines
- reducing search and transaction costs
- aiding the price discovery process by reducing informational asymmetries and, in so doing further reduce search and transaction costs, enable more informed decisions to be made, and provide shippers with the confidence that access to capacity is being provided on a non-discriminatory basis
- providing capacity holders with a greater incentive to trade capacity.

2.4 The capacity trading reforms as set out in the east coast review

The Commission made a number of recommendations in the east coast review to improve pipeline capacity arrangements to allow market participants more flexible access to transportation capacity:

- The introduction of a daily, day-ahead capacity auction for contracted but un-nominated pipeline capacity and hub services which happens shortly after nomination cut-off time. This auction is to have a reserve price of zero dollars, with compressor fuel provided by shippers in-kind. It will offer at least all contracted but un-nominated capacity and accommodate nominations or renominations by incumbent shippers after the auction is conducted.
- Standardisation of key primary and secondary capacity contractual terms for pipeline and for hub services. Standards to be developed are for key operational, prudential and other contractual provisions in Gas Transportation Agreements (GTAs), Capacity Transportation Agreements (CTAs) and Operational GTAs, and provisions in contracts used for exchange based trading on the capacity trading platform.
- The creation of capacity trading platform(s) which will include electronic anonymous exchange based trading for commonly traded products in addition to a capacity listing service.

7 ACCC, *Inquiry into the east coast gas market*, April 2016, p.149

- The publication of information on all secondary trades of pipeline capacity and hub services. The information to be published is the price of the trade and any other information that might reasonably influence that price.

2.5 The GMRG and the final recommendations for the reforms

The GMRG was established by COAG in August 2016 to lead the design, development and implementation of the capacity trading reforms in addition to other wholesale market reforms from the east coast review.

Work on the capacity trading reforms commenced in February 2017. In late 2017 the GMRG released its final recommendations for the reforms. At the 24 November 2017 COAG Energy Council meeting the COAG Energy Council agreed that the full package of reforms should be implemented by 1 March 2019.

Stakeholder consultation on the final design for the reforms will commence in mid-March and be completed by the end of April 2018.

In late May 2018 the Standing Committee of Officials (SCO) will consider the final instruments. In June 2018 the final instruments will be presented to the COAG Energy Council for approval.

The final set of recommendations from the GMRG is set out in Appendix B.[8]

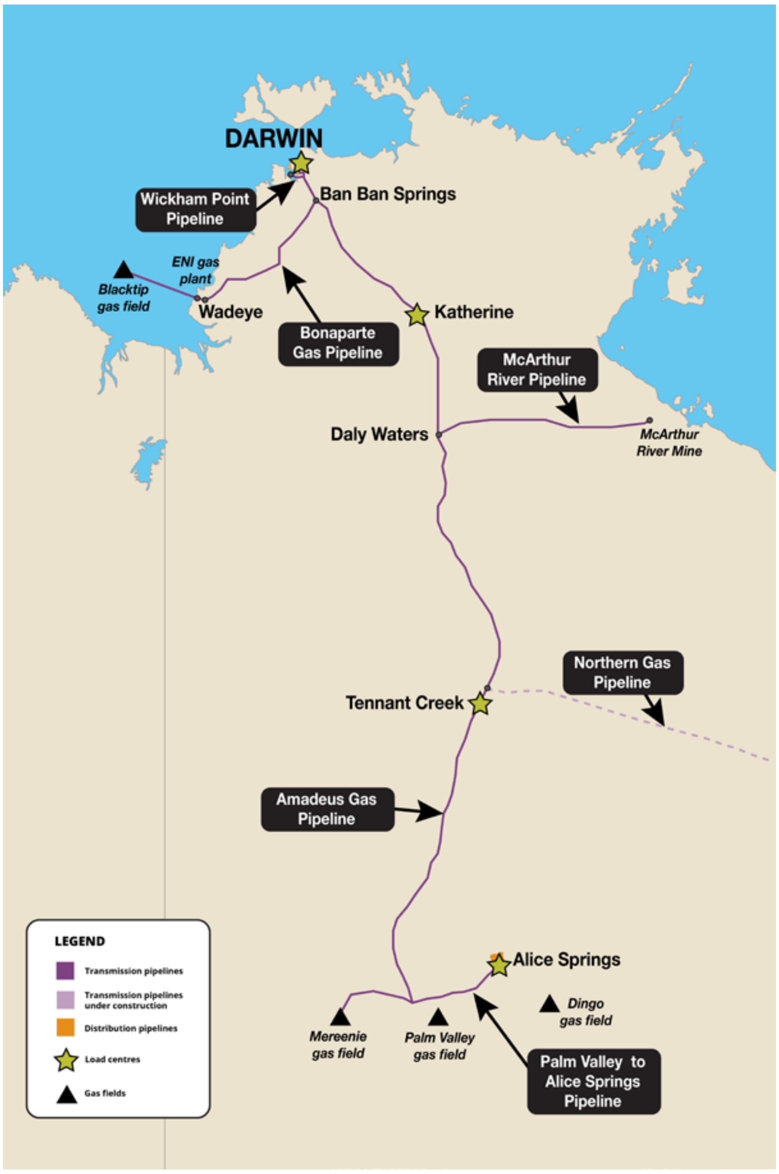
8 GMRG, Design of the Day-Ahead Auction of Contracted but Un-nominated Capacity, Final Recommendations, December 2017. GRMG, Capacity Trading Reform Package (Standardisation, capacity trading platform and reporting framework for secondary trades), Final Recommendations, November 2017

3 Northern Territory Gas Market

3.1 Key elements of the gas market

The main load centres in the NT are currently located around Darwin, Katherine and Alice Springs (Figure 3.1 below). The key supply fields are Blacktip, offshore NT and the Amadeus basin fields at the southern end of the Amadeus Gas Pipeline (AGP). The impending interconnection of the NGP with the AGP at Tennant Creek is also illustrated.

Figure 3.1 NT pipelines, major load centres and gas supply fields

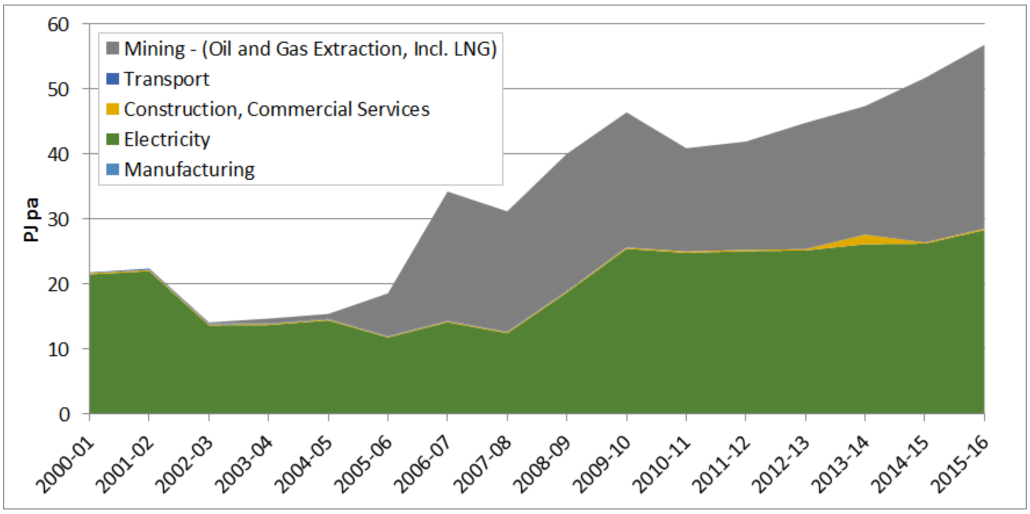


Historically the NT market has not seen the level of price volatility or scarcity of long term contracts seen in recent years in the wider east coast market. However, the lack of visibility in the NT contract market and the smaller number of participants does make comparisons difficult.

3.1.1 Demand

The NT gas market has been developed primarily to support gas fired generation (GFG) rather than as a market in and of itself. The market uses approximately 28 Petajoules (PJ) per year (see Figure 3.2) or about 75 Terajoules (TJ) per day on average.

Figure 3.2 NT gas consumption by sector



Source: Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017

There is additional load for LNG projects in Darwin but this is independent of the domestic market. There is effectively no trade between the two markets unlike on the east coast. Darwin LNG and Icthys LNG have agreements for emergency back-up gas supply to the domestic market but this has seldom been used historically.

The majority of the domestic load is in the Darwin-Katherine region. Contracts entered into by Power and Water Corporation (PWC) PWC and Territory Generation (TGen) are designed to manage the peaking gas requirement around power generation in this region.

While TGen is the largest customer for gas in the NT, there is also independent electricity producers, e.g. Energy Developments Ltd (EDL) located in the Darwin-Katherine area. In addition, Glencore's MacArthur River mine, located at the end of the MacArthur River lateral off the AGP, has in recent years augmented its GFG load on-site.

3.1.2 Supply

Before the Blacktip field came online PWC sourced gas from the Amadeus basin near Alice Springs and transported most of the gas to the Darwin-Katherine area to supply TGen's GFG requirements.

The supply of gas that PWC had relied upon from the Amadeus basin began declining in the early 2000s. PWC then entered a take-or-pay GSA with ENI that began in 2009 and runs to 2034 for gas from the Blacktip field offshore NT. This GSA is for the entire gas reserve at Blacktip. It is the Commission's understanding that the current take from the field of 65 TJ per day[9] may be below the contractual take-or-pay level.

Central Petroleum is the only other gas supplier in the region at this time. It produces gas from the same fields in the Amadeus basin (Mereenie, Palm Valley and Dingo gas fields) that historically supplied the whole of the NT. Central Petroleum's Amadeus basin fields, partly owned by Macquarie,[10] currently supply 15 TJ per day to the market but Central has plans to expand and export gas into the broader east coast market. Central Petroleum is currently undergoing a drilling program to prove up additional reserves and in company presentations, show a potential expanded facility of 59 TJ per day.[11] Central and Macquarie recently secured an interim authorisation from the ACCC for joint marketing of gas from the Mereenie gas field.[12]

Two LNG projects, Darwin LNG and Icthys LNG are located close to Darwin with connection into the Wickham Point pipeline (WPP). Both projects have emergency back-up supply arrangements with PWC to ensure supply for TGen. Both arrangements are limited in the capacity they can deliver to the domestic market based on the interconnections into the WPP (which is owned by PWC) and the impact on the flows on AGP if the WPP is fully utilised. The supply arrangements are for back-up supply only and are not intended as a connection in any trading or commercial sense to the domestic market. Stakeholders indicate this is unlikely to change for the foreseeable future. These projects are focused on LNG operations only.

3.1.3 Pipelines

Pipelines in the NT reflect both the elongated nature of the market from Darwin to Alice Springs, as well as the changing sources of supply, commencing in the Amadeus basin and now dominated by production from the Blacktip field offshore NT.

The two key pipelines the AGP and the Bonaparte gas pipeline (BGP) are operated by APA. They were developed for the purpose of transporting gas for the government owned PWC and TGen.

The AGP was completed in 1986 to take gas from the Amadeus basin gas fields of Palm Valley up to Darwin. The pipeline was acquired by APA in 2011.

In order to get gas from the Blacktip field to the load centres, it was necessary to construct a new pipeline – the BGP – from Blacktip to an interconnection point with the AGP. The BGP started to flow gas in 2009.

---

9 EnergyQuest Energy Quarterly Sept 2017

10 Mereenie gas field (Central Petroleum 50%, Macquarie 50%), Palm Valley (Central petroleum 100%), Dingo (Central Petroleum 100%)

11 Central Petroleum Media Release 2 March 2018

12 ACCC Draft determination and interim authorisation 2 March 2018

The Commission understands that PWC has a transportation agreement with APA on both the AGP and BGP. This agreement runs to 2034 and is for the entire firm capacity of these pipelines.

While currently the NT gas market is not connected to the wider east coast, Jemena is constructing the NGP which is due to be completed in late 2018. The NGP will connect the NT at Tennant Creek to the broader east coast market at Mt Isa in Queensland. It will have a nameplate capacity of 90 TJ per day on commissioning.

PWC currently has a transportation agreement for the NGP for 31 TJ per day to supply Incitec Pivot at Mt Isa and is for a 10 year duration. There are currently no other firm transportation agreements on the NGP.

Although the NGP currently has a capacity of 90 TJ per day, it can be expanded with mid-line compression to 160 TJ per day. Jemena has outlined further scenarios in which this pipeline can be expanded to 700 TJ per day, although this would involve looping and possible extension of the line to Wallumbilla.

3.1.4 Competition for gas supply and transport

Currently competition in the NT is limited with only two gas suppliers in PWC and Central Petroleum and one party, PWC, holding firm pipeline capacity on the AGP.

NT end users of gas are thought to currently contract for delivered gas only, bundling gas supply with gas transportation. However, it is our understanding that some customers in the NT are examining different arrangements – including unbundling gas supply and transportation which may result in increased competition for secondary pipeline capacity.

3.2 Historical drivers of the NT market structure

The NT market was originally set up to take supply volumes from the south in the Amadeus Basin up to the dominant market of Darwin and Katherine. As the Amadeus fields began to decline in the early 2000s, other sources were sought and in 2009 supply commenced from ENI's Blacktip field offshore NT and will continue to 2034.

The market is characterised by the predominance of GFG, and the unlegislated requirement for the key supplier PWC to act as supplier of last resort. This has meant a significant amount of offshore production capacity, offshore pipeline and onshore pipeline has been built to meet peak demand and provide security of supply. However, given that demand is often below the peak, the capacity is not fully utilised on most days of the year. Stakeholders have specified a peak of approximately twenty days of the year occurring in the lead up to the Christmas season.

The industry in NT is dominated by two large and very long term gas agreements between PWC and ENI (supply) and PWC and APA (transportation). Both agreements could be expected to reflect the cost of providing peak supply as well as baseload gas delivery.

3.3 Developments impacting the NT market

3.3.1 NGP start up

The Commissioning of the NGP will allow a significant export of gas from the NT into the broader east coast market. The NGP is a 622km pipeline owned and operated by Jemena, linking Tennant Creek in the NT with Mount Isa in Queensland. Construction of the $800 million project began in July 2017 with first gas expected at the end of 2018.[13] The pipeline will have an initial capacity of 90 TJ per day. The pipeline currently only has 31 TJ per day of the 90 TJ per day available capacity contracted.

Although the completion of the NGP may result in additional exports from the NT into the rest of the east coast, the Commission understands that generally supplying load in the NT is preferred by suppliers. Stakeholders have indicated that supplying local customers in the NT is generally more profitable.

However, given the limited demand in the NT, it is expected that additional utilisation of the NGP and increased flows into the broader east coast market will occur both from PWC and any expansion in the Amadeus basin from Central Petroleum's operations.

In the longer term new developments onshore NT will be able to utilise spare and additional capacity of the NGP. However, it is the Commission's understanding that some new production facilities may require expansion or augmentation of the AGP given its current size.

3.3.2 Moratorium on fracking

On 14 September 2016 the NT Government announced a moratorium on hydraulic fracturing (fracking) of onshore unconventional reservoirs including the use of hydraulic fracturing for exploration, extraction, production and including Diagnostic Fracture Injection Testing (DFITs).[14]

Following the moratorium, on 3 December 2016 the NT Government announced an independent scientific inquiry into hydraulic fracturing of onshore unconventional resources in the NT. The moratorium will remain in place during the inquiry. A draft final report was released on 12 December 2017. On 30 January 2018 the inquiry began its final round of hearings and community forums across the NT. The inquiry's final report is expected to be provided to the government in March 2018. No firm date has been set for the government's decision on the moratorium following the receipt of the final report.[15]

---

13 http://jemena.com.au/industry/pipelines/northern-gas-pipeline

14 https://frackinginquiry.nt.gov.au/

15 The Hon. Justice Rachel Pepper chairing the inquiry confirmed that all submissions to the inquiry must be received by 25 February. Justice Pepper committed to handing the inquiry's final report to government in March 2018. https://frackinginquiry.nt.gov.au/news/community-update-30

The moratorium has a bearing on the large shale gas development potential in the region. This includes Origin Energy's Beetaloo Basin project adjacent to the AGP, with a contingent resource of 6.6 Trillion Cubic Feet (TCF).[16] As a result, any further utilisation of pipeline infrastructure from new onshore gas developments may be dependent on if and when the moratorium is lifted.

3.3.3 Renewables policy

The NT government has committed to adopt a target of 50 per cent renewable energy by 2030.[17] The NT currently relies on conventional offshore and onshore gas as well as diesel as its primary fuel source for electricity generation. The current electricity generation fuel mix is approximately 96 per cent gas and diesel and a limited amount (4 per cent) of renewable energy.

A number of renewable projects are currently progressing in the NT:

- Rimfire Energy Group has announced plans to build a 10 megawatt (MW) solar farm near Bachelor, 100 km south of Darwin[18]
- an application has been filed for a 25 MW solar farm near Katherine. A development permit has been obtained and construction is expected to commence in 2018. This project is owned by Epuron and IGP Solar PV
- in 2016 the Darwin airport completed a 4 MW PV array to provide a significant portion of the airport's electricity needs. The second stage is looking to add a further 1.5 MW and construction has commenced. The Commission understands that the airport is also examining plans for a 40 MW PV system that will allow export of spare electricity into the Darwin-Katherine grid
- Infigen is in the preliminary stages of developing two 10 MW projects in the NT
- the Defence force has put out tenders for a 9.2 MW solar project for its Robertson Barracks about 15 km east of the Darwin CBD and a 3.2 MW array at the RAAF base, also in Darwin.[19]

Solar developments are expected to place downward pressure on the amount of electricity sourced from GFG. It is expected that this will result in less gas being required on average. However, as some stakeholders indicated peak demand will likely remain the same and may increase slightly over time with continued population growth in the Darwin area.

---

16 Origin Energy Half Year results presentation 15 February 2017.

17 https://roadmaptorenewables.nt.gov.au/

18 https://www.solarquotes.com.au/blog/northern-territory-solar-mb0307/

19 http://www.aussierenewables.com.au/directory/robertson-barracks-solar-359.html

3.3.4 LNG project development

Darwin already has one operating LNG plant, Darwin LNG. The plant is operated by Conocophillips.[20] [21] The plant is connected to the domestic network via the WPP. The WPP delivers gas in emergency situations from Darwin LNG at Wickham Point to the AGP and PWC's Weddell Power Station near Darwin.

Although connected to the NT domestic market, the Darwin LNG project is not seeking any interaction with the domestic market beyond the limited and seldom utilised emergency back-up supply it provides to PWC.

The Icthys LNG project is currently under construction. The plant is operated by Inpex.[22] [23] Icthys is also connected to the WPP and has some emergency arrangements in place with the domestic market. As per Darwin LNG, it is our understanding the project is not seeking any interaction with the domestic market beyond this emergency back-up supply arrangement with PWC.

3.3.5 New gas load

There are a number of new projects under different stages of development in the NT that would add significantly to gas load in the region. These are listed below, however, this list is by no means comprehensive. Some of these projects may be capable of operating on an interruptible basis given the nature of their operations:

- Vista Gold Mount Todd Gold Project, 50 km north of Katherine [24]
- Mt Peake processing plant near Darwin[25]
- Ammaroo Phosphate project, near Tennant Creek[26]
- Tanami Gold, off the AGP south of Tennant Creek[27]
- Mt Peake, Vanadium, Titanium and Iron Project. Mine 280 km North of Alice.[28]

---

20 Darwin LNG is owned by the following: Conocophillips 56.94%, Santos 11.5%, Inpex 11.38%, ENI 10.99%, Tokyo Timor Resources 9.19%.

21 The Darwin LNG plant has an operating capacity of 3.7 million tonnes per annum with one LNG train currently in operation.

22 The ownership structure of the Icthys LNG project is as follows: Inpex 62.245%, Total 30%, CPC 2.625%, Tokyo Gas 1.575%, Osaka Gas 1.2%, Kansai Electric Power 1.2%, JERA 0.735% and Toho Gas 0.42%

23 The Icthys LNG project has an operating capacity of 8.9 million tonnes of LNG per annum with two LNG trains. It is expected to start producing LNG early in 2018.

24 http://www.mttodd.com.au

25 http://www.tngltd.com.au/projects/mount_peake_fe_v_ti/overview.phtml

26 http://www.verdantminerals.com.au/projects/ammaroo-phosphate-project-nt

27 http://www.tanami.com.au/operations.html

28 http://www.tngltd.com.au/projects/mount_peake_fe_v_ti/overview.phtml

These new projects, if they proceed will need access to the AGP either as part of a contract for delivered gas or they may seek to obtain transportation rights themselves.

3.3.6 Other factors in the NT market

Currently in the NT there is no facilitated spot market for gas. Therefore, the price of gas and the cost of transport are not transparent. This makes it difficult for market participants and customers to easily ascertain a reference price that reflects demand and supply conditions.

As previously indicated, end use demand for gas is currently dominated by electricity generation. There are no storage assets such as LNG or underground storage and as a result linepack is the only available source to meet the systems peaking requirements. Therefore, the peaking requirement is in large part provided through offshore production flexibility and the associated pipeline infrastructure.

4 Assessment Framework and recommendation

4.1 Assessment framework for the Northern Territory Review

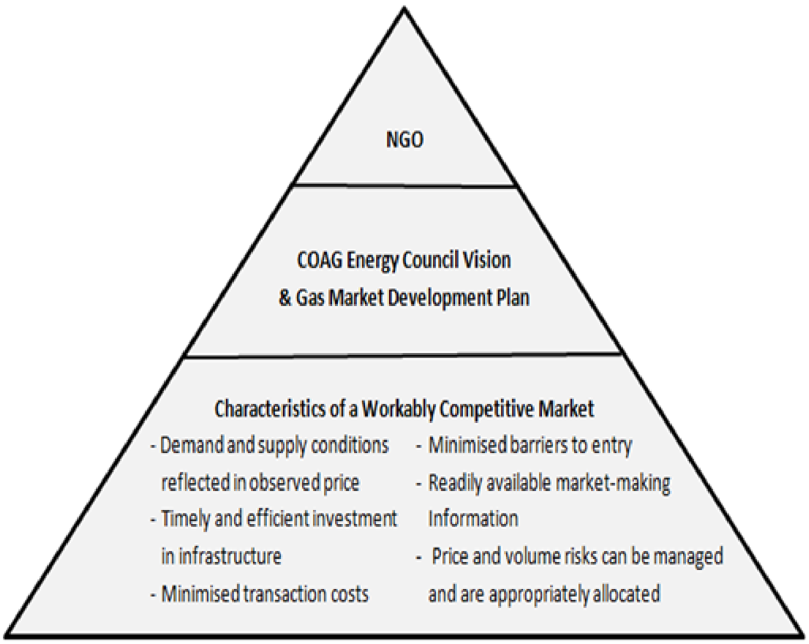
4.1.1 Assessment framework structure

In accordance with the terms of reference, the assessment framework is structured so that the single overarching objective guiding the AEMC is the NGO.

In applying the NGO, the AEMC will have regard to the Vision and Gas Market Development Plan.[29]

Sitting below the NGO and Vision are high level attributes that the Commission considers support the development of well-functioning, workably competitive markets and that are generally required for the NGO and Vision to be achieved. The relationship between the three aspects of the assessment framework is illustrated in Figure 4.1.

Figure 4.1 Assessment framework



29 COAG Energy Council Australian Gas Market Vision (December 2014) http://www.coagenergycouncil.gov.au/publications/coag-energy-council-australian-gas-market-vision

4.1.2 National Gas Objective

The AEMC must have regard to the NGO in undertaking this review. The NGO is set out in section 23 of the National Gas Law and states:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."

The NGO is structured to encourage energy market development in a way that supports the:[30]

1. efficient allocation of natural gas and transportation services to market participants who value them the most, typically through price signals that reflect underlying costs
2. provision of, and investment in, physical gas and transportation services at lowest possible cost through employing the least-cost combination of inputs
3. ability of the market to readily adapt to changing supply and demand conditions over the long term by achieving outcomes 1 and 2 over time.

The three limbs of efficiency described above are generally observable in a well-functioning, workably competitive market and together work to promote the long-term interests of consumers of natural gas.

In accordance with the NGO, the AEMC has taken into account the long-term interests of all consumers of natural gas throughout this review. In particular, although the Commission has examined the institutional and commercial arrangements present in the NT in assessing the possible application of the capacity trading reforms, the Commission's analysis is broader than just an examination of the long-term interests of consumers in the NT. It should be noted that there are numerous types of consumers of natural gas in the Australian economy including: residential and commercial users; industrial and manufacturing users; GFG; and LNG producers.

For this review, when applying the NGO the Commission had regard to the following set of high-level principles:

- competition and market signals will generally lead to better outcomes than centralised planning and regulation, as competing energy businesses have an incentive to meet consumers' needs efficiently
- where it is required, regulation should be targeted, fit-for-purpose, provide incentives that attempt to imitate the outcomes of a workably competitive

---

30 These three outcomes are commonly referred to as allocative, productive and dynamic efficiency, respectively.

market, and involve regulatory costs proportionate to the materiality of issue that the regulation seeks to address

- risk allocation and the accountability for investment decisions should rest with those parties best placed to manage them
- market and regulatory frameworks should be flexible and provide firms with a clear and consistent set of rules that allow them to independently develop business strategies and adjust to changes in the market. Frameworks should be resilient to changing supply and demand conditions, and patterns of flow, over the long-term.

These principles guide the Commission's recommendation in this review.

4.1.3 Energy Council Vision and Gas Market Development Plan

In accordance with the terms of reference, the AEMC must also have regard to the Vision for Australia's future gas market, which is as follows:[31]

> "The Council's vision is for the establishment of a liquid wholesale gas market that provides market signals for investment and supply, where responses to those signals are facilitated by a supportive investment and regulatory environment, where trade is focused at a point that best serves the needs of participants, where an efficient reference price is established, and producers, consumers and trading markets are connected to infrastructure that enables participants the opportunity to readily trade between locations and arbitrage trading opportunities."

The Vision is underpinned by four broad policy work streams and related outcomes:[32]

1. Encouraging competitive supply:
    - Improvements to the regulatory and investment environment so that gas supply is able to respond flexibly to changes in market conditions.
    - A "social licence" for onshore natural gas development achieved through inclusion, consultation, improving the availability and accessibility of factual information relating to resources projects, and rigorous science to ensure that communities concerns are addressed.
2. Enhancing transparency and price discovery:
    - Increased flexibility and opportunity for trade in pipeline capacity.

---

31 COAG Energy Council, *Australian Gas Market Vision*, December 2014, p.1

32 COAG Energy Council, *Australian Gas Market Vision*, December 2014, pp. 2-5. We note that these four work streams are also stated in the *Gas Market Development Plan*, available at: http://www.scer.gov.au/workstreams/energy-market-reform/gas-market-development/

- Competitive retail markets that will provide customers with greater choice and large users with enhanced options for self-supply and shipment.

- Provision of accurate and transparent market making information on pipeline and large storage facilities operations and capacity, upstream resources, and the actions of producers, export facilities, large consumers and traders.

3. Improving risk management:

   - Liquid and competitive wholesale spot and forward markets for gas that provide tools for participants to price and hedge risk.

   - Access to regional demand markets through more harmonised pipeline capacity contracting arrangements which are flexible, comparable, transparent on price, and non-discriminatory in terms of shippers' rights, in order to accommodate evolving market structures.

   - Harmonised market interfaces that enable participants to readily trade between locations and find opportunities for arbitrage and trade.

   - Identified development pathways to improve interconnectivity between supply and demand centres, and existing facilitated gas markets, which enable the enhanced trading of gas.

4. Removing unnecessary regulatory barriers:

   - Regulation of gas supply and infrastructure is appropriate and enables participants to pursue investment opportunities, in response to market signals, in an efficient and timely manner.

Overall, the Vision provides the Commission with a high level policy statement to guide its analysis in this review. It does this by setting out the broad direction that gas market development should take in order to meet the NGO. The elements that make up the Vision can be considered the "means" of promoting the overarching objective – the NGO – through increasing the efficiency of the gas market, for the long-term benefit of consumers of natural gas services.

4.1.4 Characteristics of a well-functioning gas market

While the NGO serves as the overarching objective and the Vision provides the high level policy direction, the AEMC is also guided by a number of attributes that represent well-functioning, workably competitive markets[33]. These are:[34]

---

33 Application by Chime Communications Pty Ltd (No 2) [2009] ACompT 2, offers a "shorthand" description of workable competition which is "...a market with a sufficient number of firms (at least four or more), where there is no significant concentration, where all firms are constrained by their rivals from exercising any market power, where pricing is flexible, where barriers to entry and expansion are low, where there is no collusion, and where profit rates reflect risk and efficiency."

1. **Demand and supply conditions reflected in prices**: markets participants should have access to a credible reference price reflective of underlying supply and demand conditions that usefully aids commercial decision making.

2. **Timely and efficient investment in infrastructure**: efficient additions to, and expansions of, infrastructure enable supply to meet demand while minimising the cost of excess capacity.

3. **Readily available market information**: efficient outcomes are likely to be achieved when participants (current and potential) have access to clear, timely and accurate information about prices and factors driving prices, such as supply and demand conditions.

4. **Price and volume risks can be managed and are appropriately allocated**: participants being able to manage operational risks to delivery of physical gas while maintaining safe operating parameters, as well as being able to insure themselves adequately against financial risks.

5. **Minimised barriers to entry**: barriers to entry (and exit) can be a function of market structure, government regulation, industry-specific sunk costs or geography, and certain barriers have the potential to detract from the ability of markets to deliver efficient outcomes.

6. **Minimised transaction costs**: efficient transaction costs support timely and efficient investments in infrastructure and encourage competition.

These characteristics, if in place, would form a strong foundation for transportation arrangements in the Northern Territory and markets linked to the Northern Territory to promote the NGO and achieve the Vision.

4.2 Commission's Findings

The Commission recommends that the following capacity trading reforms should apply in whole in the NT:

- the day-ahead capacity auction for contracted but un-nominated pipeline capacity
- the standardisation of key primary and secondary capacity contractual terms for pipeline and hub services
- the creation of a capacity trading platform
- the publication of information on all secondary trades of pipeline capacity and hub services

34 We note that these build on factors previously identified and used by the AEMC and others. See, for example: K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 86; and: ESAA, *Assessment of the East Coast gas market and opportunities for long-term strategic reform*, Final Report, May 2013, p. 37.

The capacity trading reforms will help to improve access to pipelines in the NT so that market participants are able to obtain more flexible and competitively priced pipeline capacity. The reforms will lower barriers to trading gas on a short-term basis, allowing more participants to enter the market and providing them with greater opportunity to manage risks by adjusting their portfolio positions.

The reforms will facilitate more secondary capacity trading by using market based processes to allocate capacity on a non-discriminatory basis to those that value it most highly. This will reduce search and transaction costs and information asymmetries, which in turn, will aid the price discovery process and improve the incentive shippers have to trade capacity.

The reforms will assist the NT market in managing the structural changes currently underway including new supply, additional pipeline connections, new demand and changes to the pattern of existing demand.

The NT government has committed to adopt a target of 50 per cent renewable energy by 2030, a significant increase from the current level of 4 per cent. This is likely to lead to GFG operating very differently to how it does today. The reforms will provide greater flexibility to the market to allow participants to take advantage of short-term opportunities to move gas to where it is needed while ensuring gas and transportation is available to meet peak demand.

The day-ahead auction of contracted but un-nominated pipeline capacity will promote increased trading of secondary capacity over time. This will promote more efficient utilisation of the pipeline, both in the short term and long term. Over time, as further competition enters the NT market, the day-ahead auction will allow new participants to access pipeline capacity. Although the capacity obtained through the day-ahead auction is not a substitute for firm capacity, it allows parties to obtain access while negotiating firm contracts with either the pipeline owner or the incumbent shipper. It also provides an incentive on incumbent shippers to enter into contracts for unutilised capacity. This is especially relevant in the NT where one shipper has all the firm capacity on the AGP in the NT.

The capacity trading platform and contract standardisation will reduce the time taken to execute trades in secondary pipeline capacity. The platform will reduce search costs and provide a mechanism for incumbent shippers to trade pipeline capacity. Standardisation will serve to make secondary trading more fungible. This will provide parties greater flexibility and ease of trading.

The reporting framework will provide information to the market to allow participants to more easily determine a reference price for pipeline capacity. It will provide shippers with confidence that access is being provided on a non-discriminatory basis.

The capacity trading reforms, together with the connection of the NT to the broader east coast market, will lead to both short and long-term efficient use of pipeline capacity. Further, the reforms balance the incentives on incumbent shippers and pipeline owners to trade capacity while maintaining effective investment signals for new or augmented pipeline infrastructure given the very short term nature of the capacity products offered through the reforms. Although there are some costs associated with the reforms, these are expected to be incremental and are outweighed by the benefits to consumers over the long-term.

As a result of the government ownership of the PWC (the incumbent shipper) there may be possible impacts on the taxpayers of the NT arising from the reforms. In particular, the day-ahead auction may result in competitors of PWC or TGen being able to obtain pipeline capacity for the reserve price (zero dollars plus compressor fuel in kind). This may result in competitive pressures on PWC to either price delivered gas at below their cost or lose out to competitors or TGen for contracts (for supply, transportation or both). However, the ownership issues in the NT are not part of the Commission's assessment of the NGO. These issues are best addressed by the NT government in balancing the various economic benefits that may arise from the reforms and the opening of the market against the possible financial impacts on PWC.

5 Assessment against the framework

The review has applied the same assessment framework as was used for the east coast review, taking into account the particular structure of the NT market and the commercial agreements that have underpinned the development of the market.

In its assessment of the application of the reforms in the NT, the Commission has taken into account that the wider east coast market is characterised by several interconnected markets that may have different supply, demand and operational characteristics.

While interconnection will result in gas flow between the NT and the wider east coast market, it does not imply gas prices will be closely linked. The distances involved and the cost of transport between the NT and the wider east coast market is likely to result in differences between NT and east coast gas contract prices, as well as the level of price volatility.

5.1 Day-Ahead Auction

5.1.1 Issues the reform is set to address

The day-ahead auction addresses the issue of contractual congestion of pipelines where shippers are not fully utilising their contracted capacity and are hoarding this capacity and prospective shippers are unable to gain access. Generally, incumbent shippers currently have an incentive not to on sell un-nominated capacity given the cost and effort of doing so and the risk of not having capacity available when needed may exceed the revenue generated. This is especially the case with PWC in the NT where they need to be capable of supplying peak demand at all times.

It has been suggested by some market participants that shippers are making it difficult for new entrants to acquire firm capacity in order to improve their competitive position.

As the only seller of capacity beyond the nomination cut off time, the pipeline owner has the ability and incentive to price contracted but un-nominated capacity above levels expected in a workably competitive market. The pricing of capacity by pipeline owners, where it is above what would be expected in a workably competitive market, is likely to affect the efficient utilisation of capacity over time.

The combination of high prices for this capacity and shippers limited incentive to trade appears to have resulted in inefficient outcomes in the east coast market where spare capacity with a low marginal cost is underutilised.

There may also be co-ordination failure for shippers looking to move gas across multiple pipelines due to the complex nature of the contracted but un-nominated market. Multiple buyers need to transact with multiple sellers over multiple legs. This is prohibitive to trade. This will be especially true in the NT once the NGP is connected where parties want to move gas from the NT into the broader east coast market.

Currently there are no means of transacting for secondary capacity in the NT apart from bilateral negotiations. These may be lengthy, complex, expensive or infeasible particularly for short-term trades.

5.1.2 How the reform addresses the issues

The day-ahead auction provides shippers with the opportunity to purchase competitively priced capacity rather than be priced out of the market or having to search and transact on a bilateral basis.

In cases where capacity is being deliberately withheld, the auction will provide shippers with the opportunity to purchase competitively priced capacity after the nomination cut off. It would be expected that the capacity obtained through the auction will be less costly than bilateral negotiations.

The auction will provide a platform to simultaneously coordinate trades across multiple pipelines or pipeline segments, allocating capacity to the combination of shippers that value it most highly. This will allow shippers in the NT to gain access to the wider east coast market and allow for a more efficient mechanism to coordinate transportation across multiple pipelines including the AGP in the NT.

From an efficiency perspective a whole network auction will optimise allocation across as many products as possible, given different complementarities between different lengths of pipeline.

The zero reserve price (plus compressor fuel in kind) will allow shippers that value capacity most highly to access that capacity providing they are willing to pay at least the cost of provision (ie, the cost of compressor fuel). The Commission found in the east coast review that setting the reserve price at short run marginal cost (zero dollars plus compressor fuel in kind) is appropriate as anything above this may affect allocative efficiency because valued capacity may go unutilised.

In order to maintain an incentive on the incumbent shipper to sell capacity prior to the auction, auction revenue is to be allocated to pipeline owners.

Recognising that the day-ahead auction mechanism does result in some costs to the market, there may be circumstances where it is not appropriate to require all un-nominated capacity to be included in the auction. Therefore, the Commission recommended that pipelines that serve only a single shipper be exempt from the auction.

5.1.3 Application to the Northern Territory

The auction will provide prospective shippers with the opportunity to purchase competitively priced capacity. It will incentivise existing capacity holders to trade pipeline capacity that is not being fully utilised ahead of the auction.

The auction will provide for a more efficient mechanism of pricing and allocating capacity on the different sections of the AGP line once it is interconnected with the NGP. The line may become three sections once the NGP is connected - the northern section flowing from the interconnection of the BGP with the AGP north to Darwin, a middle section flowing from the same point south to Tennant Creek and the underutilised southern section flowing north from Alice to Tennant Creek. If the pipeline is divided in this way in the auction, these sections will have different levels of usage and competition.

It is understood that there is some concern that the day-ahead auction may impact on investment in the infrastructure in NT as some shippers would be able to access very short term capacity at potentially low cost (the reserve price) when they require it. These shippers would therefore access transportation without the long term commitments used to underwrite investment.

The Commission does not consider that this is likely to be a material issue in practice. Very few shippers would be able to rely solely on day-ahead capacity to manage their transportation needs over medium to long-term periods. This is because relying on capacity purchased through the auction results in the shipper facing price risk (the auction price may be very high) or volume risk (no capacity is available).

In the NT, where an investment is made, it is acknowledged in the short term there may be limited price risk if there are few shippers who participate in the auction but over time, as more competition enters the market this is unlikely to continue. Further, the trading platform allows the incumbent shipper to offer spare capacity to the market and recover the benefit. These agreements can be structured for different time periods to take advantage of the shippers changing needs including when it needs all of its contracted firm capacity.

In addition, the auction will help to provide better price signals for investment in new pipeline capacity in the NT. This is because as existing primary capacity is more fully utilised, the price paid for secondary capacity at the auction increases due to the supply of un-nominated capacity decreasing.

It is expected that the auction will greatly simplify the process of transporting gas across multiple pipelines in the NT and across multiple pipelines into the east coast market, given the auction is designed to combine bids across multiple pipelines in one combinatorial auction.

The NT market is largely a market for gas for the purposes of GFG. Combined with the expected growth in renewables under government plans for 50 per cent renewable target by 2030, the auction will help the market to better utilise pipeline capacity in periods where gas demand is not peaking. This requirement will grow as the profile of gas demand through the day changes.

While the NT is a smaller market the cost benefit trade-off is expected to be favourable given the two pipeline operators, Jemena and APA, are required to implement the reforms for their east coast operations. The operator of the day-ahead auction, AEMO, will be using the same systems across the east coast and so the incremental costs of including the NT should be relatively small. The longer term benefits to the interconnected east coast market may be significant with additional upstream development in NT and fuller utilisation of the NGP gas pipeline which is currently not fully contracted.

5.2 Capacity Trading Platform

5.2.1 Issues the reform is set to address

There are numerous factors that limit the ability of prospective shippers to access competitively priced secondary transportation capacity:

- a lack of information on the existence of prospective buyers and sellers of capacity resulting in high search and transaction costs, particularly for short-term capacity trades. Buyers and sellers are unable to find each other, and so trades that would otherwise occur do not
- limited information on the market for both buyers and sellers, which may lead to additional costs as the parties attempt to understand the market value and determine whether they are being offered capacity on a non-discriminatory basis
- highly customised GTAs, which can make it difficult for participants to quickly and inexpensively determine the value of the capacity rights being sold in order to make a trade. Customisation also limits the liquidity of the market because a range of different products splits the market.

5.2.2 How the reform addresses the issues

The capacity trading platform will serve to reduce search and transaction costs and the time required to execute trades. Shippers will be able to simply and anonymously post or review buy or sell offers on the platform up to the nomination cut off time.

Capacity products will be more fungible and therefore capable of being readily valued and traded through an exchange. Shippers will be able to quickly assess whether the price on offer is consistent with historical transactions.

The standardisation of secondary capacity products traded through the platform will likely lead to increased liquidity of trading.

The platform provides an incentive on incumbent shippers to trade unused capacity. Unlike the auction, they will retain the proceeds of any capacity sales carried out through the capacity trading platform.

Shippers will gain confidence that future secondary trades are non-discriminatory, which when coupled with the anonymous nature of trading, will reduce perceived barriers to entry and enhance competition.

A single capacity trading platform that covers all contract carriage assets will help to achieve the objective of harmonising the trading arrangements across the wider east coast market, including the NT, once the markets are interconnected.

The Commission recognises that there may still be a role for bilateral trades outside the platform, and that forcing all trades through the platform may discourage some participants from trading. To counter this potential, more bespoke transportation products can be advertised ahead of time on the capacity trading platform listing service so that other shippers have an opportunity to compete for this trade.

5.2.3 Application to the NT

The capacity trading platform will help to reduce search and transaction costs in the NT for pipeline capacity trades. Participants are currently dispersed across different states and negotiations have been challenging for participants.

Information on trades of secondary pipeline capacity has been limited and a source of some disagreement in the NT. The NT would greatly benefit from greater visibility on prospective and historical trades.

The capacity trading platform is likely to facilitate greater utilisation of the AGP line. It does this through lowering search and transaction costs, reducing the time it takes to trade and increasing liquidity through standardisation of products, which in turn may lead to the greater utilisation of the NGP pipeline over time.

Currently the incentive for PWC to trade its capacity on the AGP may be inhibited by its upstream supply agreement liability and its desire to acquire new customers. While PWC has made it clear that it has offered secondary capacity on the AGP on a number of occasions, the auction in combination with the trading platform will provide a stronger incentive for PWC to offer firm capacity that it is not utilising.

5.3 Standardised provisions in capacity agreements to make capacity more fungible

5.3.1 Issues the reform is set to address

The contracts underpinning secondary capacity trades on the east coast have historically been quite bespoke, with a range of terms of terms and conditions customised to meet the requirements of the contracting parties. The Commission understands that this is also the case in NT.

5.3.2 How the reform addresses the issues

The reform will help to facilitate a greater level of secondary trade through reducing search and transaction costs by making it easier for shippers to value and compare secondary capacity and reducing the provisions to be negotiated.

The reform does not result in all terms being standardised but allows participants more easily to determine which terms are not standard. Gas day start times will be harmonised across the east coast to 6 am Australian Eastern Standard Time (AEST).

The reform is intended to increase the pool of prospective sellers of secondary capacity by making it easier for primary capacity holders to change their receipt and delivery points and in so doing increase liquidity in the market.

To the extent that standardisation can be achieved across pipelines then it will also remove any unnecessary impediments to trade across pipelines.

Under the reform the standardised operational GTA will consist of a set of:

- standard operational, prudential and other legal terms governing the relationship between the secondary shipper and the service provider that will apply to all facilities
- facility specific terms, which may differ across facilities due to differences in operational and contractual arrangements.

While service providers will have some discretion in relation to facility specific terms, these terms will need to comply with a number of principles that will be set out in the Operational GTA Code, a new regulatory instrument that will set out the standard terms to be adopted by all service providers and the requirements for facility specific terms.

Standardising these service dimensions will result in more fungible capacity products that are capable of being traded through an exchange.

5.3.3 Application to the NT

The AGP pipeline has a different contractual arrangement to other pipelines on the east coast including the NGP pipeline. Rights to capacity are structured around injection and withdrawal rights rather than a forward haul or back haul service. However, the standardisation of terms for secondary capacity and the benefits flowing from it are not dependent on the contractual or access arrangement terms associated with primary capacity.

Standardisation of key contract terms in secondary capacity agreements will assist shippers in being able to compare secondary capacity products on this line with the NGP and other east coast pipelines. It will help to reduce the provisions that need to be negotiated between primary owners of capacity and would be secondary shippers both for transport within NT and into the east coast network.

By making it easier for prospective sellers to change receipt and delivery points it will increase liquidity in the NT market over time. The potential pool of buyers and sellers at particular delivery points will increase with additional delivery point flexibility.

The NT market has seen very little trade of secondary pipeline capacity to date. Standardisation of capacity provisions could be expected to benefit the NT market significantly, while also removing impediments to trade into the east coast.

5.4 Reporting Framework

5.4.1 Issues the reform is set to address

The prices and terms on which secondary capacity trades are struck are currently confidential. As a result, shippers have no way to determine whether the secondary capacity is being provided on a non-discriminatory basis, or if the prices they are offered are reasonable.

This may particularly deter new entry by shippers with smaller gas portfolios, who, unlike a large shipper, may consider that they do not have the ability to negotiate a good deal with the pipeline owner. Importantly, the perception of non-discriminatory access is as important as the practise of non-discriminatory access to overall confidence in the market and hence liquidity.

5.4.2 How the reform addresses the issues

The reform requires the publication of information on all secondary trades of pipeline capacity and hub services. Information to be published includes the price of the trade and any other information that might reasonably influence the price, taking into account measures to protect the anonymity of the counterparties.

Greater transparency as a result of this reform is expected to:

- aid the price discovery process for secondary capacity trades, and by doing so reduce search costs and expedite the transaction process
- provide for efficient allocation and use of capacity because shippers will be able to readily assess the market value of capacity and make informed decisions
- enable shippers to engage in more effective negotiations and provide them with the confidence that access is being provided on a non-discriminatory basis.

The reform will instil a greater level of confidence in the secondary market, which may in time support the development of a more liquid wholesale gas market.

Transparent historical prices, terms and conditions should place a discipline on shippers not to undertake price discrimination.

5.4.3 Application to the NT

Discussions with both primary and secondary shippers have indicated a wide disparity in accounts of the amount of capacity available, the nature of the service, for example the degree of firmness, and the price. As such the NT market will greatly benefit from the reporting framework reform.

The reform is likely to lower the transaction costs for pipeline capacity trading for existing primary and secondary shippers and also lower the information barriers to new shippers looking to enter the market.

The reform should provide for more efficient allocation of pipeline capacity because shippers will be able to assess the different value of capacity on the different sections of the AGP line. As the movement of gas on the AGP changes with the interconnection with the NGP, this value should evolve both on commissioning of the pipeline and as investments are made in upstream and downstream facilities to more fully utilise the pipeline.

New entrants with significant offshore resources have indicated that while the size of their developments would necessitate new infrastructure, greater visibility around access to pipeline capacity and its cost, would benefit the commercialisation process of new fields. This applies to projects located offshore Darwin and onshore along the route of the AGP.

There is a cost associated with the capacity trading platform, standardisation and reporting reforms. While the NT market is small relative to the east coast and the number of participants that would initially find a benefit from the platform within the NT market could be limited, the costs should be manageable given the same pipeline operators (APA, Jemena) are required to implement these reforms in the east coast. The operator of the capacity trading platform and reporting framework, AEMO, will be using the same systems across the east coast and so the incremental costs of including the NT should be relatively small. In the longer term the benefits are expected to outweigh any incremental costs.

5.5 Stakeholder consultation

The AEMC has consulted widely with stakeholders in the NT, on interconnecting pipelines and in east coast markets. Stakeholders from government, gas supply, LNG production, gas transportation, gas wholesale, gas retail, electricity retail and large gas consumers have provided input to the review.

Generally feedback from stakeholders considered that the reforms fit into two baskets: the day-ahead auction in one basket, and the capacity trading platform, standardisation of contract terms and information provision in the other. Stakeholders were divided on the benefits of the day-ahead market with some being of the view that the reform would help the market and others who viewed the reform unnecessary or harmful to the NT market.

Stakeholders either provided input to the effect that they have no issue with the platform, standardisation and reporting framework reforms or they feel that these reforms will provide a much needed increase in clarity in the market.

The cost of implementation was raised by stakeholders in relation to the capacity trading platform standardisation and reporting framework reforms. However the Commission notes that all the operators of assets in the NT that would bear an additional administrative burden from the reforms are already required to implement the reforms in relation to their other operations in the east coast. The addition of the NT is unlikely to add disproportionately to this task.

In relation to the more polarising day-ahead auction reform, the incumbent shipper, PWC, indicated that it has attempted to trade firm capacity on reasonable terms in the past but that other shippers are waiting until such time as they can participate in the auction and receive the capacity for the reserve price of zero dollars (plus the cost of compressor fuel).

PWC has underwritten both the construction of the BGP and the AGP (the majority of the capital costs have now been paid with the exception of the BGP). As a result of PWC now sourcing gas from Blacktip in the north rather than from supply near Alice Springs, a number of parties noted that portions of the pipeline in the south are now underutilised and as a result this capacity would likely be available through the auction at zero or very low cost.

PWC indicated that in the NT the auction reform would result in a perverse incentive whereby the incumbent shipper would be willing to trade capacity but other shippers would rather participate in the auction.

Central Petroleum on the other hand indicated they have been unable to negotiate firm capacity on reasonable terms. Further both Central Petroleum and other participants indicated that it had been challenging and time-consuming to negotiate with either PWC or APA to obtain any type of capacity (firm or interruptible) on the AGP. They have indicated that the auction would act as an incentive to the incumbent shipper to trade this capacity ahead of the auction, and without the auction the incumbent shipper has limited incentive to trade capacity to competitors on reasonable terms.

The NT government and other interested parties have indicated that they see that in the short term a shipper may be able to obtain capacity for zero dollars. However, the auction, together with the other reforms, should encourage other developments and shippers into the market and result in those other parties being able to more easily access the pipeline.

5.6 Response to stakeholder concerns in relation to the day-ahead auction

Many of the issues raised by stakeholders were considered either by the AEMC as part of the east coast review or by the GMRG in developing the reform package. This includes the potential that a shipper may be able to secure capacity for zero dollars.

The Commission does not consider it an inefficient outcome of the auction for a participant to receive capacity for zero dollars in the case where the supply of capacity exceeds the demand but rather results in the efficient use of the pipeline by those parties that value it.

Further, in the NT, although sections of the pipeline have spare capacity (in particular Alice Springs to Tennant Creek) other sections are fully utilised. It is recognised that in the short-term there are underutilised sections of the AGP where there is only one non-incumbent shipper. However, the Commission is of the view that over the mid to long term this may not remain the case, resulting in increased demand for transportation on the AGP. The ability of a shipper other than PWC to access sections going to the major load centres is more difficult and a shipper would face risks that on a day-ahead basis no capacity would be available. This aligns with the Commission's finding in the east coast gas review that the capacity secured in the day-ahead auction is not a substitute for firm capacity.

The ability of a shipper to gain access to the section of the AGP that is underutilised, at very low cost, may also lead to more efficient use of the NGP pipeline, which is currently under-contracted. The economics of export both to Mt Isa and to more distant east coast markets is challenging, particularly for participants looking to secure the necessary funds to finance upstream development. A more efficient transportation cost on some of the lines providing transport into the east coast may facilitate development that would not otherwise occur and so assist in the contracting of the NGP pipeline.

In the event that the day-ahead auction were not implemented in a region where a single shipper has all the pipeline capacity and acts as a retailer, it will be difficult for a consumer to access a more competitive deal as it may be unable to secure the needed capacity. This provides the incumbent shipper/retailer with a significant degree of market power. This is potentially the issue at present in the NT market. That is, no other shipper is able to obtain firm rights to pipeline capacity and they are therefore required to either offer contracts to customers on a non-firm basis or to risk that they will not be able to supply the customer when needed. In some instances this requires the customer to take risks on the security of gas supply in order to introduce some level of competition to the market.

The auction, although the rights are not firm, creates incentives for the incumbent shipper to trade capacity that it is neither fully utilising at present nor has plans to utilise in the foreseeable future. This is in the interests of long-term consumers both in the NT and in interconnected markets.

5.7 Considerations outside the NGO

A component of the NT gas market that is not shared in the east coast gas market is the ownership structure of PWC and TGen and the unlegislated requirement that these parties act as supplier (either of gas or electricity) of last resort.

As a result of these arrangements there is an obligation on these parties to ensure that sufficient gas and transportation capacity is available at all times to ensure that TGen can meet the electricity demands of the NT. Therefore, the contracts these parties entered into for supply and transportation may not have the same terms and conditions as you would expect from a private enterprise.

Further, as PWC and TGen are government entities any impacts on their finances would impact the taxpayers of the NT.

Therefore, there is a potential impact on NT taxpayers in that the auction may result in unfavourable competitive conditions for PWC. This may result in PWC either losing out on new contracts (for supply, transportation or both) or having to enter into those new contracts below their cost level (which is not necessarily below market cost). Alternatively PWC's existing or new customers may unbundle the supply of gas from the transport of gas and opt to contract with a different gas supplier or shipper.

To the extent that this situation eventuates in the NT market as a result of the reforms, and this is by no means certain, NT taxpayers may be faced with some losses on the long-term transportation agreement with APA for the AGP. Where TGen is able to unbundle supply and transport, the lower cost of transport may help to balance out any loss to PWC. However, where the benefit might accrue to a private enterprise in that a competitor could acquire capacity at low cost in the auction, but charge end users based on a tariff only slightly below the rate offered by PWC, taxpayers would be subject to a loss without a corresponding benefit.

However, on the other hand, the reforms may support additional development occurring in the NT that might not otherwise proceed under an unchanged market structure. This development would aid the economy and be a benefit to taxpayers and potentially result in increased employment in the NT.

Although the Commission is aware that there are possible impacts on NT taxpayers (separate from the impacts and benefits to NT consumers) as a result of the structure of the parties and contracts in the NT market, these impacts are best addressed by government in balancing the various benefits and possible drawbacks to taxpayers and the NT economy overall.

5.8 The impact of the application of the reforms in the Northern Territory on the wider east coast market

With the interconnection of the NT gas market with the wider east coast market from the end of 2018, the NT market will form one part of a series of interconnected gas markets stretching from Darwin in the NT to Hobart in Tasmania. For the reforms to provide the benefits that were foreseen in the COAG Energy Council's vision for east coast gas markets and for Australian gas markets as a whole, the application of the capacity trading reforms in the NT is an important step in achieving that vision.

The benefits to the interconnected markets of applying the capacity trading reforms in the NT apply both in the short and the long term and apply across all elements of the gas supply chain. They encompass:

- **East coast supply demand benefits.** The introduction of the reforms may enhance the likelihood that near term developments go ahead. Central Petroleum have made it clear that as well as targeting sales in the NT and Mt Isa, they also see the potential for storage products in the east coast market using the NGP to access that market. The addition of a new competitor into the east coast market, even with small volumes, or providing a storage product, may help the competitive dynamic on the east coast and so benefit consumers.

  The reforms may facilitate increased sales into the Mount Isa region. Where this occurs, it will improve the east coast gas balance as these volumes are currently supplied from other east coast supply sources.

  Given the challenging economics of supplying baseload NT gas supply into east coast markets beyond Mt Isa in the longer term, day-ahead sales using the auction may provide a low cost route to market where short-term price signals in east coast markets allow.

- **Greater liquidity in all wholesale markets.** The reforms are likely to facilitate greater flows of gas between the NT and the broader east coast market for the same reasons as they will facilitate flows of gas around the east coast and within the NT gas market. By incentivising shippers to release capacity they are not utilising, reducing search and transactions costs, standardising terms to make capacity more fungible and increasing participants confidence in the market. The combinatorial nature of the auction should facilitate trades involving multiple pipelines across the NT and the east coast for delivery into east coast spot and wholesale markets.

  This will help to concentrate liquidity at the points of the network where it can provide the greatest benefit to consumers.

- **More efficient use of the existing and newly built pipeline network, as well as clearer investment signals.** The reforms should lead to better allocative efficiency in the use of the interconnected network in relation to existing pipelines as well as recently completed pipelines such as the NGP. The reforms will help to provide better pricing signals on which part of the interconnected network should be expanded. There are scenarios in the future in which an expansion of the NT network may be more efficient for consumers than an expansion of a pipeline on another part of the east coast. Having an interconnected network with capacity trading reforms in place across the network will enable these signals to be compared and the most efficient option taken by market participants.

- **Greater range of long-term resource development options.** Longer term supply development in the NT is likely to be facilitated by the reforms. While discussions with stakeholders indicated large developments would in the most part seek access to LNG markets or would need pipelines with a capacity well in excess of the AGP/NGP connection, these stakeholders did indicate that the reforms are likely to assist in the development of resource projects. Better access to east coast markets is likely to facilitate upstream developments in NT which will in turn provide the interconnected market with more supply options overall and with a greater diversity of participants.

- **Gas demand growth encouraged in regions where resources and pipeline capacity are lowest cost, providing benefits to economic growth.** The reforms may facilitate demand growth or continuing demand at Mt Isa. Previously this may not have been expected given the high prices prevalent in the east coast market and the high cost of transport along the South West Queensland pipeline (SWQP) and the Carpentaria Gas Pipeline (CGP) in order to deliver gas to Mt Isa. The reforms may facilitate growth at other points on the interconnected network where there is spare pipeline capacity and gas is able to move to these points with greater efficiency.

- **Shared benefit of matching different seasonal load patterns across the network.** With greater integration and trade across the interconnected network, facilitated by the reforms, some shifting of gas volumes between regions on a daily or even seasonal basis could be expected. This is more likely to occur once participants have clarity around the costs of moving gas between regions either on a day-ahead basis or through longer term deals facilitated by the reform package.

  While stakeholders have suggested the NGP pipeline will not be configured on a bi-directional basis on commissioning, they have also indicated that the design of the pipeline allows for bi-directional flow with a small additional investment. Bi-directional flow on the NGP in the longer term means both the NT and the wider east coast market may be able to benefit each other at different times of the year depending on daily and seasonal usage patterns.

Overall, the Commission is of the view that the application of the capacity trading reforms in the NT are in the long-term interests of consumers. The reforms will promote the efficient use of pipeline capacity in the short and long term and provide valuable information to the market on the cost associated with secondary capacity in the NT and wider east coast markets.

Abbreviations

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AEST	Australian Eastern Standard Time
AGP	Amadeus gas pipeline
BGP	Bonaparte gas pipeline
CGP	Carpentaria Gas Pipeline
COAG	Coalition of Australian Governments
CTAs	Capacity Transportation Agreements
EDL	Energy Developments Ltd
FEED	Front End Engineering and Design
GFG	gas fired generation
GMRG	Gas Market Reform Group
GSAs	Gas Supply Agreements
GTAs	Gas Transportation Agreements
MW	megawatt
NERA	National Energy Resources Australia
NGO	National Gas Objective
NGP	Northern Gas Pipeline
NT	Northern Territory
PJ	Petajoules
PV	Photovoltaic
PWC	Power and Water Corporation

SCO	Standing Committee of Officials
SRMC	Short Run Marginal Cost
STTM	Short Term Trading Market
SWQP	South West Queensland pipeline
TCF	Trillion Cubic Feet
TGen	Territory Generation
TJ	Terajoules
WPP	Wickham Point Pipeline

A Stakeholder List

Name	Category
NT Government - Treasury and Finance	Government
NT Government - Strategic Infrastructure and Projects	Government
NT Government - Gas Governance Group	Government
NT Utilities Commission	Government
QLD government - Natural Resources, Mines and Energy	Government
ACCC	Government
GMRG	Government
Power and Water Corporation	Wholesale
Central Petroleum	Producer
ENI	Producer
Santos	Producer
Origin Energy	Producer
Pangaea Resources	Producer
ConocoPhillips	LNG producer
Inpex	LNG producer
Jemena	Pipeline
APA	Pipeline
Territory Generation	Gas User
EDL	Gas User
AGL	Gas User
Incitec Pivot	Gas User
Jacana Energy	Electricity User
Gas Trading Australia	Consultant
Craig Langford (MDQ Consulting)	Consultant

B GMRG Final Recommendations

Table B.1 Summary of the GMRG's final recommendations on the day-ahead auction design

<table>
<tr><th colspan="2">Design Element</th><th>Recommendation</th></tr>
<tr><td rowspan="2">Coverage of auction</td><td>Coverage</td><td>The GMRG recommends that the following facilities be subject to the day-ahead auction:
• all transmission pipelines with a capacity rating of 10 TJ/day and above that are providing third party access and servicing more than one facility; and
• the Moomba and Wallumbilla compression facilities currently operated by APA.</td></tr>
<tr><td>Exemptions</td><td>The GMRG recommends that exemptions be available to transmission pipelines that have a nameplate capacity rating of less than 10 TJ/day; are not providing third party access; or are servicing a single facility</td></tr>
<tr><td rowspan="2">Product design</td><td>Products to be auctioned</td><td>The GMRG recommends that the following products be auctioned:
• Forward haul transportation services (with separate products offered in both directions on bi-directional pipelines).
• Compression services provided by the Moomba and Wallumbilla compression facilities.
• Interruptible backhaul services on single direction pipelines.</td></tr>
<tr><td>Prioritisation of the forward haul and compression auction products</td><td>The GMRG recommends that:
• The forward haul and compression auction product be classified as a second priority firm service, which in relation to the contracted but un-nominated capacity will rank below firm transportation rights and the renomination rights (firm and reasonable endeavours) of firm capacity holders, but above all the other transportation rights from a scheduling, curtailment and renomination rights perspective.</td></tr>
</table>

Design Element		Recommendation
		• Transitional arrangements be put in place to accommodate any existing as available or authorised overrun services, where the service provider would be in breach of existing contractual commitments if it scheduled those services after the forward haul and compression auction products. The GMRG also recommends that as part of the 2020 Biennial Review, the AEMC consider whether: • the second priority firm service prioritisation is providing firm capacity holders with a sufficient incentive to trade their capacity before the auction and encouraging participation in the auction, or if the priority should be increased; and • an intra-day auction(s) should be introduced, or other measures implemented to facilitate intra-day trading, to enable capacity on the gas day to flow to those that value it most.
	Other features of the auction product	The GMRG recommends that the specification of the auction product provide for: • a maximum hourly quantity (MHQ) factor that is equal to the MHQ factor set out in the service provider's operational Gas Transportation Agreement (operational GTA), which will also apply to capacity purchased through the capacity trading platform; and • a reasonable endeavours renomination right. The auction product will not, however, include an imbalance allowance but measures will be put in place to facilitate trading of imbalance allowances.
	Contract path specification	The GMRG recommends that: • a case-by-case approach be adopted, which could involve a combination of point-to-point and zonal approaches; • further work be carried out in early 2018, in conjunction with AEMO, service providers and other stakeholders, to specify the contract paths on each pipeline that will be subject to the auction.

Design Element		Recommendation
		The GMRG also recommends that measures be implemented to ensure that information on the contracted but un-nominated capacity at delivery points does not directly or indirectly disclose a nomination made by a market generating unit as defined in the National Electricity Rules.
	Other	The GMRG recommends that: • as available and interruptible services not be phased out, but in relation to contracted but un-nominated capacity, these products will (subject to the transitional arrangements outlined above) be scheduled after the auction product, so they do not compete with auction products; • during the gas day service providers will be able to sell on an interruptible basis any unutilised contracted but un-nominated capacity with such capacity to rank after the auction product in the priority order; and • market conduct rules be implemented to deal with the risks associated with renominations by both firm capacity holders and auction winners
Auction format	**Auction quantity**	The GMRG recommends that service providers have some discretion to determine the methodology to be used to calculate the contracted but un-nominated capacity on their respective pipelines, but in developing this methodology they will be required to have regard to principles in the NGR and any procedures that may be developed by AEMO. The methodology will also need to be approved by AEMO and published on either the National Gas Services Bulletin Board (BB) or the auction platform. The AER will also be able to monitor service providers' compliance with the approved methodology.
	Auction format	The GMRG recommends that a partial combinatorial auction format be adopted and include the static backhaul optional feature. This auction design will enable shippers to procure capacity across multiple pipelines and the Moomba and Wallumbilla compressors, irrespective of location or pipeline ownership. The GMRG also recommends that at market start the minimum requirement and XOR bidding optional features not be included, but that this be reconsidered in the future if there is sufficient demand for these features and benefits of their inclusion in the auction format outweigh the costs.
	Reserve price	The GMRG recommends that a zero reserve price be adopted with compressor fuel either provided by shippers in-

Design Element		Recommendation
		kind, or by the service provider with the costs then recovered through the operational GTA
	Pricing rule	The GMRG recommends the adoption of a pay-as-cleared pricing rule, which will be determined by the lowest accepted bids in the auction and that auction winners be determined using the profit-maximising combination of bids.
	Auction residue	The GMRG recommends that the auction residue be allocated to service providers based on the revenues achieved by the products owned by each service provider. This allocation method will ensure that scarcity is remunerated and acts as a signal for further investment
	Curtailment	Because the auction product will not be a firm product, additional measures are required to deal with the risk of curtailment, which could occur as a result of renominations by firm capacity holders or technical constraints. The GMRG recommends that this risk be addressed as follows: • auction winners should be able to try and avoid curtailment by procuring primary capacity from the service provider of the asset that is experiencing the curtailment if such capacity is available and, if they are unable to do so, should have the option to choose whether they are only curtailed on that asset; or curtailed by the same amount across all products included in the winning bid; and • if curtailment is required, it should occur on a pro-rata basis and auction winners should receive their money back for the curtailed capacity
	Information provided to bidders	The GMRG recommends that: • before the auction, auction participants be told what products are available in the auction and the auction quantity; and • after the auction, auction participants be provided with information on their own winning bids, including the quantities of each product procured and the price of all products in the auction. The GMRG also recommends that the bid-stack not be published until sufficient liquidity develops in this market, but as an interim measure AEMO publish information on the aggregate demand for each segment and the high, low and

Design Element		Recommendation
		average surplus for each segment on the BB.
Cost recovery	**AEMO**	The GMRG recommends that the costs AEMO incurs in implementing and operating the auction be recovered from auction and capacity trading platform participants and that AEMO have discretion to extend the recovery mechanism to all gas supply hub (GSH) trading participants if necessary. The GMRG also recommends that AEMO be required to consult with auction and capacity trading platform participants on the structure, introduction and determination of fees.
	Service providers	The GMRG recommends that the incremental costs that service providers incur as a result of the auction, be recovered from the auction proceeds and if these are insufficient, service providers should have an opportunity to recover these costs from shippers, subject to the caveat that the charges are cost reflective and, so far as practical, reflect the outcomes of a workably competitive market. To impose some constraint on the charges levied by service providers, the AER will have the power to conduct a review of these charges and require amendments if they do not comply with the pricing principle outlined above.

Table B.2 Summary of the GMRG's final recommendations on the capacity trading platform

Design Element	Recommendation
Operation of the capacity trading platform	The GMRG recommends that the capacity trading platform, which will be operated by AEMO and form part of the GSH trading exchange, provide for both: • **Exchange-based trading** of commonly traded transportation (pipeline and compression) products, which can be conducted through either: — the screen trade service, which allows participants to place anonymous bids or offers for standardised products that are automatically matched; or — the pre-matched trade service, which allows participants to bring a bilateral trade in one of the GSH products to the exchange

Design Element	Recommendation
	for settlement. The screen trade service will operate on a fully anonymous basis (i.e. the names of counterparties will not be revealed pre-or post-transaction), with AEMO informing the relevant service provider of the trade once it has been executed. The service provider will then confirm the trade with each counterparty separately, maintaining the anonymity of the trading parties through this process. • **A listing service** that shippers can use to list more bespoke transportation products and imbalance trades. Trades conducted through the exchange will utilise the existing GSH settlement, prudential and reporting frameworks, which means participants will receive one settlement statement for all traded products and be able to aggregate prudential requirements across gas and secondary capacity products
Initial set of services to be listed on the exchange	The GMRG recommends that the initial set of standardised products to be sold on the exchange include: • firm forward haul services on all major transmission pipelines (if the pipeline is bi-directional, services will be available in both directions); • firm compression services at Moomba and Wallumbilla; and • firm park (storage) services on all the major transmission pipelines. These products will be available as day-ahead, daily (available on a 6-day rolling basis), weekly (available on a 4 week rolling basis) and monthly (available on a 3 month rolling basis) products and will have a minimum contract size of 500 GJ/day. The terms and conditions on which the buyer can use these products will be set out in the Operational GTA, which, amongst other things, will specify the maximum hourly flexibility the buyer will have and provide the buyer with a reasonable endeavours renomination right.
Zonal model	The GMRG recommends that a zonal model with secondary firm rights at receipt and delivery points be used to maximise the pool of prospective buyers and sellers of firm forward haul services through the capacity trading platform. To implement this model, receipt and delivery point zones will need to be established on each pipeline that will be listed on the exchange and will need to reflect the technical pipeline requirements and market requirements.

Design Element	Recommendation
Management of financial and delivery default risks	There are two key risks that buyers will be exposed to under the proposed design of the capacity trading platform: • The seller's primary GTA is terminated by the service provider: In this case, the GMRG recommends that the service provider be obliged to honour the transaction for up to two weeks after the primary GTA is terminated and receive the price established through the exchange in return for doing so. The GMRG believes this approach is necessary because the buyer will not know the seller's identity so will be unable to carry out its own assessment of the financial viability of its counterparty prior to entering into the trade. By keeping the trade on foot for two weeks, buyers will have time to find alternative arrangements, which will promote an orderly transition and minimise the impact of default on the gas market. • The seller short-sells capacity: In this case, the GMRG recommends that service providers give the seller an hour to rectify the short position and if it can't be rectified, the trade be cancelled and the buyer(s) compensated. Because individual counterparties will not be known, if a trade is cancelled all secondary shippers' capacity would be pro-rated down.
Governance arrangements	The GMRG recommends that the governance framework that currently applies to the GSH be maintained, but the necessary changes be made to the NGR, the Exchange Agreement and procedures to accommodate capacity trading and the recommendations set out above. In relation to the zonal model, the GMRG recommends that any proposal to change the zones be submitted to the Industry Panel for consideration and approved by the AER. Principles will be included in the NGR to guide this process and enable any person to make a request to change the zone

Table B.3 Summary of the GMRG's final recommendations on the standardisation related reforms

Design Element	Recommendation
Capacity transfer mechanisms to be used for secondary trading	Consistent with the AEMC's recommendations, the GMRG recommends that: • Operational transfers be used to give effect to capacity purchased through the capacity trading platform, the day-ahead

Design Element	Recommendation
	auction and bilateral trades where the buyer elects to use an operational transfer • Bare transfers be allowed in cases where capacity is purchased through bilateral trades, subject to the caveat that the sellers of secondary capacity offers the buyer the option of using an operational transfer Under both types of transfers, the primary shipper's capacity rights (or part thereof) are temporarily transferred to the secondary shipper and the obligation to pay the service provider remains with the primary shipper. The main difference between the two mechanisms is that under an operational transfer, the secondary shipper is responsible for making nominations directly to the service provider (rather than via the primary capacity holder) and complying with the terms and conditions of access set out in the operational GTA it enters into with the service provider.
Contract standardisation	**Standardisation of operational GTAs** The GMRG recommends that priority be given to standardising operational GTAs, given these contracts will be used to give effect to trades conducted through the capacity trading platform and the day-ahead auction, and will also have to be offered under bilateral trades. The standardised operational GTA will operate like a master agreement between the service provider and secondary shipper, and set out the terms and conditions on which the secondary shipper can utilise the service provider's services if it procures secondary capacity via an operational transfer It will be mandatory for service providers that provide third party access to publish a standard form operational GTA on their website and to offer to enter into this agreement with secondary shippers (subject to some limited qualifications and exemptions). The NGL and NGR will not, however, prohibit service providers and shippers agreeing to vary the terms, include other services in the agreement, or include the transfer mechanism in a primary GTA. The terms on which capacity is sold through the capacity trading exchange or day-ahead auction will be set out in the Exchange Agreement and the Auction Agreement. For bilateral trades, the shippers buying and selling capacity will agree terms between themselves in Capacity Trading Agreements (CTAs).
	Content of the standardised Operational GTA and level of standardisation

Design Element	Recommendation
	The standardised operational GTA will consist of a set of: • standard operational, prudential and other legal terms governing the relationship between the secondary shipper and the service provider that will apply to all facilities; and • facility specific terms, which may differ across facilities due to differences in operational or contractual arrangements. While service providers will have some discretion in relation to the facility specific terms, these terms will need to comply with a number of principles that will be set out in the NGR, the requirements set out in the Operational GTA Code (a new regulatory instrument that will set out the standard terms to be adopted by all service providers and the requirements for facility specific terms) and will also be subject to oversight by the AER The GMRG has developed an initial draft of the Operational GTA Code, which stakeholders have provided some feedback on. The initial draft did not, however, make provision for the day-ahead auction product because the design of the auction had not been settled. The GMRG intends therefore to release another draft of the Operational GTA Code for consultation in early 2018.
	Service provider costs The capacity trading reform package will impose a number of incremental establishment and capacity trading costs on service providers. The GMRG recommends that service providers have an opportunity to recover these costs, subject to the caveat that the charges are cost reflective and, so far as practical, reflect the outcomes of a workably competitive market. To impose some constraint on the charges levied by service providers, the GMRG also recommends that the AER be given the power to: • conduct a review of a service provider's charges if it has concerns about their level (or if concerns are raised by an interested party); and • require amendments to the charges if it finds that they do not comply with the pricing principle outlined above.
	Governance arrangements

Design Element	Recommendation
	The standard terms and requirements for the facility specific terms will be set out in an Operational GTA Code, which will be a new regulatory instrument developed under the NGL/NGR. Once the initial Code is made it will be subject to a hybrid governance model, which will involve the following: • AEMO will be responsible for establishing an Industry Panel to consider changes to the Operational GTA Code and provide secretariat services to the panel. AEMO will also be responsible for carrying out consultation on behalf of the Industry Panel and requesting input from the AEMC, where required. • Changes recommended by the Industry Panel will only take effect if approved by the AER. In deciding whether to approve the changes, the AER will be required to take into account the panel's recommendation (but will not be bound by it), the NGO and principles in the NGR. The AER is considered the most appropriate body to take on this role, because it is consistent with its current role in relation to approving the terms and conditions of access to covered pipelines and is not subject to the same types of conflicts that AEMO or the AEMC would be subject to. Under the proposed governance framework, the AER will also: • be responsible for monitoring service providers' compliance with the obligation to publish the standard operational GTA and that the facility specific terms and charges levied by service providers for entering into these arrangements, are consistent with the Operational GTA Code and NGR principles; • have the power to exempt a facility from the requirement to publish a standardised operational GTA (e.g. if it is not providing third party access).
Other measures to reduce barriers to secondary trading and participation in the auction	**Allocation arrangements** To reduce the opaqueness currently surrounding allocation agreements, information on the allocation agents a secondary shipper would need to contact to become a party to an allocation agreement at all the relevant points should be published on the Natural Gas Services Bulletin Board (BB) The GMRG also recommends that further work be carried out by the GMRG, in consultation with AEMO and industry, in early 2018 to address the allocation issues at Moomba and determine whether additional reforms are required to reduce the

Design Element	Recommendation
	other barriers to trade posed by allocation arrangements. The GMRG will also work with the ACCC to determine whether any additional transparency measures are required in relation to allocation agreements
	Contractual limitations on capacity trading in primary GTAs There are a number of provisions in primary GTAs that may prevent or impede secondary trading. To ensure these do not act as a barrier to secondary capacity trading, the GMRG recommends that: • Provisions that prohibit primary shippers from trading capacity, or require primary shippers to obtain a service provider's consent before they can trade capacity, be addressed through provisions that will require service providers to allow users to transfer contracted capacity to another party, without the service provider's consent, if the user remains liable for capacity payments and the transferee has an operational GTA • Provisions that prohibit primary shippers from requesting changes to receipt and delivery points, or limit the number of changes that can be requested, be addressed through provisions detailing the rights shippers have to seek changes to receipt or delivery points; the timeframes within which service providers must respond; and the pricing principle to apply to charges levied by the service provider for these changes (i.e. charges should be cost reflective and reflect the outcomes of a workably competitive market). The provisions are expected to draw on the approach in rules 105(2) and 106(1) of the NGR, which apply in relation to scheme pipelines.
	Harmonisation of gas day start times and nomination cut-off times To remove the barriers to trade posed by differences in gas day start times and nomination cut-off times, the GMRG recommends that changes be made to the NGL/NGR to require the adoption of: • a common gas day start time of 6 am (AEST) across the east coast (and the Northern Territory once it becomes connected) and apply to the operators of all production, pipeline, compressor and storage facilities; and • a common nomination cut-off time of 3 pm (AEST) for pipelines and other facilities that will be subject to the capacity

Design Element	Recommendation
	trading reforms The GMRG recommends these changes take effect by 1 October 2019

Table B.4 Summary of the GMRG's final recommendations on the reporting framework for secondary capacity trades

Design Element	Recommendation
Trades subject to reporting	The GMRG recommends that the reporting framework apply to: • all screen and pre-matched trades carried out through the capacity trading platform; and • bilateral trades of capacity involving forward haul, backhaul, park, park and loan and/or compression services Capacity purchased through the auction will also need to be reported but the reporting framework will be slightly different. The GMRG's recommendations on the day-ahead auction reporting framework will be made to the Energy Council in December.
Information to be reported	The GMRG recommends that the reporting framework require the following information to be reported: • the date of the trade and the start and end dates for the trade; • the type of trade (e.g. exchange traded or bilateral) and how it is given effect (e.g. operational GTA, primary GTA or bare transfer); • the type of service procured (i.e. forward haul, backhaul, park, park and loan, compression), the firmness of the service and service priority; • the pipeline or compression facility the trade relates to and, in the case of pipeline services, the direction of the

Design Element	Recommendation
	service and zones between which gas is transported (zones will be used to, the extent practicable, protect the anonymity of counterparties); • the amount of capacity procured (expressed on a maximum daily quantity (MDQ) and maximum hourly quantity (MHQ) basis); and • the price paid for the capacity (including, where relevant, details of the price structure and price escalation mechanism for bilateral trades).
Responsibility for reporting	The GMRG recommends that: • AEMO be accorded responsibility for reporting trades carried out through the capacity trading platform; and • sellers be accorded responsibility for reporting bilateral trades.
Where and when information is to be reported and published	The GMRG recommends that trades carried out: • through the capacity trading platform be reported on the GSH by AEMO as soon as practicable after the trade occurs (consistent with what currently applies for commodity) and published on the BB website by the end of the gas day; and • bilaterally be reported to AEMO by the earlier of one day after the trade is executed, and the day prior to the trade commencing (D-1) and published on the BB website by AEMO by the end of the gas day.
Requirement to advertise bilateral trades	The GMRG has some concerns about the workability of the proposal to require bilateral trades be advertised on the listing service ahead of time. As an alternative, the GMRG is recommending that these trades be subject to the reporting framework, with the prices and other key terms struck in these trades published on an ex post basis. The publication of this information is intended to discourage parties from engaging in any form of discriminatory behaviour, but if the reported information reveals this type of behaviour is occurring, the AEMC could recommend further changes as part of its biennial review of liquidity in the wholesale gas and pipeline capacity trading markets.

Design Element	Recommendation
Governance arrangements	A number of changes will need to be made to the NGL and NGR to give effect to this reporting framework Changes to the NGL will be required to impose an obligation on sellers to provide AEMO with information about bilateral trades and permit AEMO to publish information on these trades and trades carried out through the capacity trading platform, in accordance with the NGR and applicable procedures. Changes will also need to be made to the NGR to set out the specific obligations that: • sellers have to report information to AEMO, including the types of trades to be reported, the information that must be reported and the timing for reporting; and • AEMO has to report the trade information on the GSH and BB website. Secondary trading reporting procedures will also need to be developed by AEMO The AER will be responsible for monitoring and enforcing compliance with these obligations using its existing powers in the NGL